

A HYDRAULIC PROCESS FOR INCREASING THE PRODUCTIVITY OF WELLS

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ABSTRACT

The oil industry has long recognized the need for increasing well productivity. To meet this need, a process is being developed whereby the producing formation permeability is increased by hydraulically fracturing the formation.

The "Hydrafrac" process, as it is now being used, consists of two steps: (1) injecting a viscous liquid containing a granular material, such as sand for a propping agent, under high hydraulic pressure to fracture the formation; (2) causing the viscous liquid to change from a high to a low viscosity so that it may be readily displaced from the formation.

To date the process has been used in 32 jobs on 23 wells in 7 fields, resulting in a sustained increase in production in 11 wells.

INTRODUCTION

Need For Process

Although explosives, acidizing, and other methods have long been used, there still exists a need for artificial means of improving the productive ability of oil and gas wells, particularly for wells which produce from formations which do not react readily with acids. This paper discusses the development of a hydraulic fracturing process, "Hydrafrac", which shows distinct promise of increasing production rates from wells producing from any type of formation. The method is also considered applicable to gas and water injection wells, wells used for solution mining of salts and, with some modification, to water wells and sulphur wells.

Requirements of Process

In considering such a possible process, it appeared that certain requirements must be met. Some of these are as follows:

A. The hydraulic fluid selected must be sufficiently viscous that it can be

injected into the well at pressure high enough to cause fracturing.

- B. The hydraulic fluid should carry in suspension a propping agent, such as sand, so that once a fracture is formed, it will be prevented from closing off and the fracture created will remain to serve as a flow channel for oil and gas.
- C. The fluid should be an oily one rather than a water-base fluid, because the latter would be harmful to many formations.
- D. After the fracture is made, it is essential that the fracturing fluid be thin enough to flow back out of the well and not stay in place and plug the crack which it has formed.
- E. Sufficient pump capacity must be available to inject the fluid faster than it will leak away into the porous rock formation.
- F. In many instances, formation packers must be used to confine the fracture to the desired level, and to obtain the advantages of multiple fracturing.

Development of Process

As a necessary step in the development of this process, it was deemed advisable to determine if the Hydrafrac fluids were actually fracturing the formation or whether these special fluids were merely leaking away into the surrounding formation. To determine this, a shallow well, 15 feet deep, was drilled into a hard sandstone. Casing was set, the plug drilled, and the well deepened in the conventional manner. A fracturing fluid dyed a bright red was used to break down the formation. Sand mixed with distinctively colored solids was injected into the well with the fracturing fluid to prop open any fracture made in the formation. A simulated gel breaker solution dyed a bright blue was then pumped into the well to determine if the gel breaker would follow the first solution.

The results are shown in Figure 1. It was noted that a fracture was formed about the well bore, that the propping

agent was transported back into the break, and that the breaker solution did actually follow the fracturing gel out into the fracture.

While it is realized that this shallow well test is probably not exactly equivalent to a deep test, the results were interpreted as being a definite indication of what happens down the hole during a Hydrafrac job.

Of interest in this connection is an investigation reported by S. T. Yuster and J. C. Calhoun, Jr.¹ This study, reported after the Hydrafrac work was under way, presents some excellent field data supporting the theory of fracturing a formation with hydraulic pressure.

METHOD

Steps of Hydrafrac Process

Figure 2 shows a simplified cross-sectional view of a well treated by one version of the process. The first step, formation breakdown, is done with a viscous fluid, usually consisting of an oil such as crude oil or gasoline, to which has been added a bodying agent. Due to availability and price, war-surplus Napalm has been used in the majority of experiments to date. Napalm is the soap which was used in the war to make "jellied gasoline". The next step consists of breaking down the viscosity of the gel by injecting a gel-breaker solution and then after several hours, putting the well back on production. Figure 3 shows diagrammatically, a typical field hookup. The oil or gasoline is unloaded into the 10 bbl. tank shown on the left rear of the truck. This base fluid is picked up by the mixing pump and pumped through the jet mixer, where the granular soap is added. Next it goes into a small mixing tub, from which the high-pressure pump takes suction. The solution is then pumped into the well. The breaker solution is then taken from an extra tank and is displaced into the well immediately following the gel. When required, additional trucks may

¹References are at the end of the paper.

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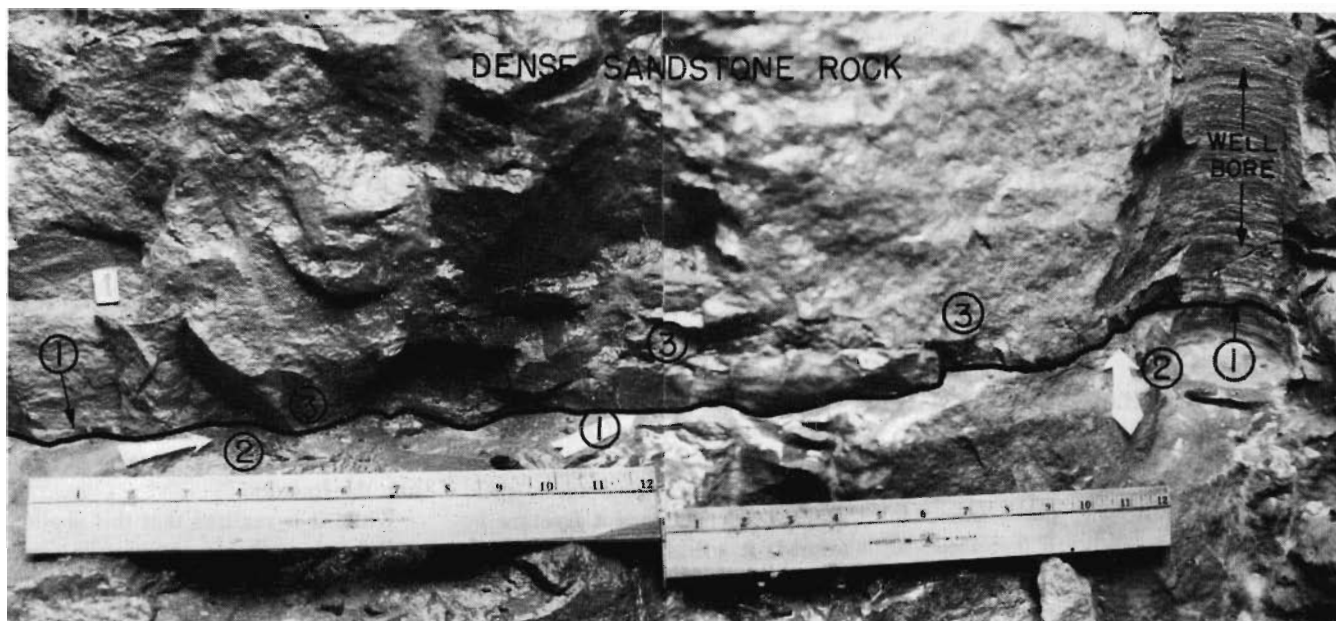


FIG. 1 — SHALLOW WELL HYDRAFRAC JOB, SHOWING (1) FORMATION FRACTURE CONTAINING FRACTURING LIQUID (2) EXPOSED FORMATION PROPPING AGENT AND (3) ROCK ADJACENT TO THE FRACTURE PARTIALLY SATURATED WITH SIMULATED GEL BREAKER SOLUTION.

be connected to the well so as to pump the fluids at a faster rate.

Planning the Field Job

The planning of a Hydrafrac job requires detailed consideration of the individual well conditions. Selection of the pumps and of the kind and amount of hydraulic fluid, for example, depends upon the thickness and permeability of exposed producing formation; the bottom hole formation pressure; the well depth; the pipe size and condition; and upon the weight, strength, and compressibility of the overburden.

Individual items that must be considered in the planning, and the method of meeting the detailed requirements for the fracturing fluid and equipment are discussed in detail below, under the corresponding headings of hydraulic fluid requirements, pump requirements, and packer requirements.

Hydraulic Fluid Requirements

The usual hydraulic fluid requirement is for an oil phase material with viscosity between 50 and 150 centipoises or higher, depending on the individual job. It has been found that Napalm soap and similar soaps provide the desired characteristics. Napalm can be added to gasoline, kerosene or other refined petroleum cuts to produce gels having any desired viscosity up to considerably over 300 centipoises.

Hydraulic Base Fluids: The ideal fluid should be an oily one rather than a water base fluid, to avoid decreasing the permeability of the formation to oil or gas. This requirement is met by the Napalm gel being used. Water base fluids, however, would be

advantageous in treating water wells, or water injection wells used in either the oil industry or industries where water is used in solution mining of salts, and in the Frasch process of mining sulphur. There is also some reason to believe that a water base fluid could be used successfully in oil or gas wells. In other words, it is entirely possible that the benefits derived from hydraulically fracturing the formation may be great enough to overcome the decrease in permeability caused by water wetting of the oil or gas sand. It is known, for example, that limestone reservoirs can be acidized with an acid solution that is as high as 80 or 90 per cent water, with a resulting increase

in well productivity. Future work with this process may indicate that it is more economical to use a water base for the hydraulic fracturing fluids than the more expensive gasoline and crude oil base fluids, particularly in formations not appreciably contaminated with argillaceous materials.

Sand Carrying Capacity of the Fluid: It is often desirable that the hydraulic fluid should carry in suspension a sufficient amount of strong granular material such as sand to be used as a propping agent to keep the fracture from closing off after release of pressure. The high viscosity of the Napalm gels makes them well suited to transport such material.

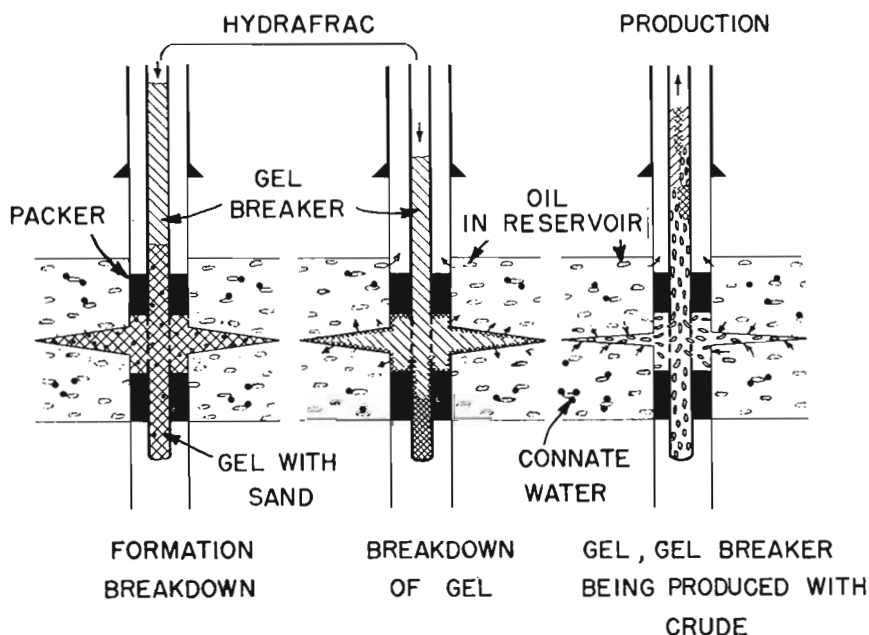


FIG. 2 — SEQUENCE OF STEPS IN HYDRAFRAC PROCESS.

Breaking of the Fracturing Fluid Viscosity: After the fracture is made, the fracturing fluid must be thin enough to flow back out of the well. The Napalm gels have the advantage of being relatively unstable, so that the viscosity of the solution will revert to approximately that of the base oil after the fracture is formed.

A further advantage of the Napalm gel is that its time of reversion to a sol is controllable within definite limits. For example, it has been found that $\frac{1}{2}\%$ to 1% of water added to a Napalm-gasoline gel will cause reversion to a sol within 8 to 24 hours, which gives ample time for performing the Hydra-frac job. Napalm-gasoline gels will revert to sols within an hour or two if they are in quiescent contact with either salt water or many types of crudes. Furthermore, it is also possible to use solutions which will break these gels in a few minutes under quiescent contact conditions. One example is a 2% solution of petroleum sulphonates in gasoline or crude oil. This allows one to follow the Napalm gel with a second solution to insure its more rapid reversion to the sol condition.

Pump Requirements

Field experience has shown that the successful Hydrafrac treatment requires a definite fracturing of the formation, as indicated by a decrease in injection pressure; this decrease in pressure is clearly shown on several of the charts presented later.

Starting with well depth, fluid viscosity, formation thickness and permeability, and bottom hole pressure, it is possible to compute with fair accuracy, by an empirical method, the pump rate necessary to fracture a formation and to extend the fracture after it is made. It is also possible to determine the necessary fluid viscosity to fracture and to extend the fracture in the formation with a given pump rate.

Table 1 compares calculated breakdown pressures with those observed in the field. A comparison of the data presented in this table indicates a close agreement between the two figures.

Table 2 illustrates typical results of such computations. It is apparent from this table that, in formations of normal permeability, it is impossible to employ a fluid of high penetrating ability, such as the usual low-viscosity crude oil, for fracturing or extending the fracture. On sands such as in the East Texas Field, it would require a

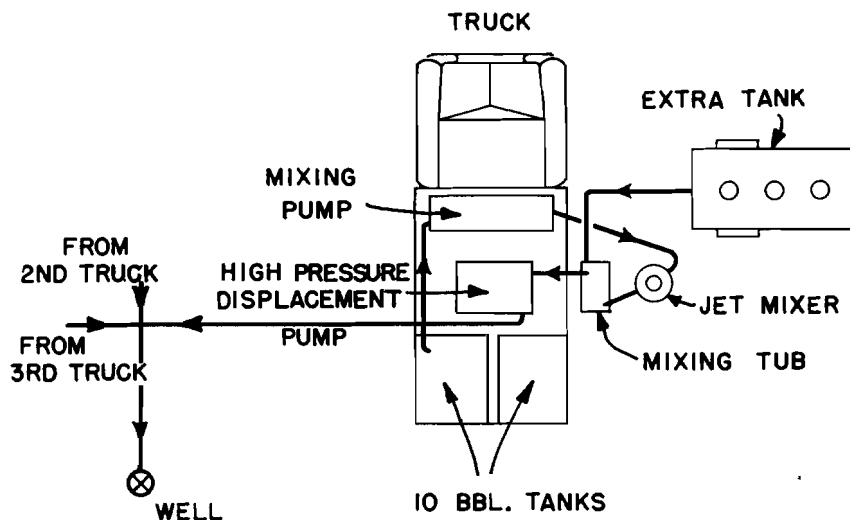


FIG. 3 — WELL HOOK-UP USING SERVICE COMPANY EQUIPMENT

TABLE 1
Calculated vs. Actual Formation Breakdown Pressures

Field	Well	Bottom hole Pressure (psi)	
		Calculated	Actual
East Texas	GA	3,000	3,350
Rangely, Colorado	EF	4,800	4,900
Hugoton, Kansas	AA	2,500	2,000
East Sasakwa, Oklahoma	FA	2,600	2,400
Frannie, Wyoming	BB	2,700	2,750

TABLE 2
Pump Rate to Fracture Hydraulically

	East Sasakwa Field Booth Sand	Hugoton Field Ft. Riley Lime	East Texas Field Woodbine Sand
Amount of open hole	35 ft.	35 ft.	20 ft.
Average formation permeability	150 md	13 md	2,000 md
Bbl/min to fracture			
Crude oil—5 centipoises	2	.13	21
Gel—100 centipoises	0.1	.007	1
Bbl/min to extend fracture to 50 ft. radius			
Crude oil—5 centipoises	11	1	213
Gel—100 centipoises	0.6	0.05	10.7
Pressure to fracture	2,100* 1,250**	1,700* 900**	2,900* 1,700**
Pressure to extend fracture	1,700* 850**	1,350* 550**	2,600* 1,400**

*Bottom hole pressure (psi)

**Surface pressure (psi)

crude oil injection rate of 21 bbl/min at approximately 2,000 psi in order to fracture the formation, which is beyond practical limits, since the largest portable oilfield pumps deliver only about 3 bbl/min at this pressure. However, it is obvious from Table 2 that by using a higher viscosity material such as a 100 centipoise gel, the pump requirements are dropped to within practical limits both for fracturing and for extending the fracture.

Packer Requirements

In wells where the exposed sand section is quite thick, special precautions must be taken so that the hydraulic fracturing operation can be performed at more than one depth. Ordinarily, the formation will fracture but once, and the relative increase in production due to this single fracture might be negli-

gible in a well having a large amount of productive sand thickness. To obtain the benefits of multiple fracturing, it is necessary to set special formation packers against the wall of the hole so as to isolate sections of a few feet in thickness before applying the Hydra-frac process. This technique is also important where it is necessary to prevent the fracturing fluids from entering non-productive formations which may alternate with the producing zones exposed to the well. Packers are also required in some instances to keep the high pressures of the process from injuring pipe. Inflatable packers have been found best for this work, but due to the fact that such packers are still in the development stage, considerable mechanical difficulty has been experienced with them.

Hazards

The Hydrafrac process is accompanied by a considerable hazard to personnel. The materials usually used are inflammable and explosive, and this, together with the use of internal combustion engines, makes this process rather hazardous. It is believed, however, by exercising due caution such as covering mixing tubs and piping off engine exhausts that this process need not be more hazardous than the handling of any other inflammable liquid. The treating solutions have not ignited on any of the jobs done to date.

FIELD RESULTS

Wells Showing Sustained Increases in Production

The experimental application of the Hydrafrac process to oil and gas wells has resulted in sustained and significant increases in productivity on 11 wells out of the 23 in which it has been tried. A compilation of some of the key data obtained on these wells is shown in Table 3.

Six of these 11 successes are gas wells in the Hugoton Field; in one instance, a combination Hydrafrac-acid job was done, resulting in increasing deliverability from 53 to 439 MCF per day; an increase from 53 to 322 MCF per day was the result of the Hydrafrac treatment, with a further increase to 439 MCF per day being the result of the subsequent acid job. On a Hydrafrac treated well, the deliverability was increased from 0 to 258 MCF per day, where the average of the offset wells completed by acidization indicated an increase in deliverability from 0 to 230 MCF per day. It is not possible at this time to make a complete evaluation of the advantages or disadvantages of a Hydrafrac-acid job or of a Hydrafrac job, over an acid job alone, but a program of comparison is in progress which will involve a sufficient number of wells to arrive at a definite answer.

A much stronger case for the economic possibilities of the process is found in the five oil wells in which Hydrafrac has resulted in sustained production increases. These are as follows:

Frannie Field, Wyoming: Well BB increased from 60 to approximately 160 bbl/day and the Well BC from 60 to 72 bbl/day as the result of Hydrafrac treatment; both these increases have been sustained for over a year.

East Sasakwa Field, Oklahoma: Well FA in this field, which was producing no oil and was to be abandoned, has

TABLE 3
Results of Hydrafrac Field Tests

Field, Well	Formation Breakdown	Sand Injection	Production			Percent Increase
			Before	After	Increase	
Hugoton (Gas) Field, Kansas (A)						
Well AA.....	Yes	No	769 MCF	1015 MCF	246 MCF	32*
Well AB†.....	Yes	Yes	53	322	269	508
Well AC†.....	Yes	Yes	0	258	258	Infinite
Well AD†.....	Yes	Yes	0	322	322	Infinite
Well AE†.....	Yes	Yes	0	**	—	—
Well AF†.....	Yes	Yes	0	**	—	—
Frannie, Wyoming (B)						
Well BA.....	Yes	Yes	27 BOPD	27 BOPD	0 BOPD	0
Well BB.....	Yes	Yes	60	160	100	167
Well BC.....	Yes	No	60	72	12	20
Well BD.....	Yes	No	65	65	0	0
Elk Basin, Wyoming (C)						
Well CA.....	No	Yes	0 BOPD	0 BOPD	0 BOPD	0
Winkelman Dome, Wyoming (D)						
Well DA.....	No	Yes	91 BOPD	91 BOPD	0 BOPD	0
Rangely, Colorado (E)						
Well EA.....	No	Yes	100 BOPD	65 BOPD	-35 BOPD	-35
Well EB.....	No	Yes	100	100	0	0
Well EC.....	No	Yes	40	30	-10	-25
Well ED.....	No	Yes	106	100	-6	-6
Well EE.....	No	Yes	25	25	0	0
Well EF.....	Yes	Yes	75	140	65	87
East Sasakwa, Oklahoma (F)						
Well FA.....	Yes	Yes	0 BOPD	6 BOPD	6 BOPD	Infinite
East Texas (G)						
Well GA.....	Yes	Yes	0 BOPD	50 BOPD	50 BOPD	Infinite
Well GB.....	No	Yes	4	4	0	0
Well GC.....	Yes	Yes	8.25	8.25	0	0
Well GD.....	Yes	Yes	3.5	3.5	0	0

*Combined effect of Hydrafrac and acid.

†One of four producing zones treated.

**No post-Hydrafrac production this date.

MCF—1000 cubic feet per day.

BOPD—Barrels of oil per day.

produced from five to six barrels per day for nine months since Hydrafrac treatment.

East Texas Field: Well GA which had produced no oil for two years produced more than 50 barrels of oil per day for several weeks while under special test after a Hydrafrac treatment, before being returned to its 20 barrels per day allowable rate. This well has been producing at the 20 barrels per day rate for five months since then, with periodic productivity

tests to determine the maximum potential of the well. The last special test of this type indicated a well potential of 61 barrels of oil per day.

Rangely Field, Colorado: Well EF which was producing approximately 75 barrels of oil per day before treatment, is now producing approximately 140 barrels of oil per day as the result of Hydrafrac treatments.

Figures 4, 5, 6, and 7 show for four of the above wells, the production curve before and after treatment, and the

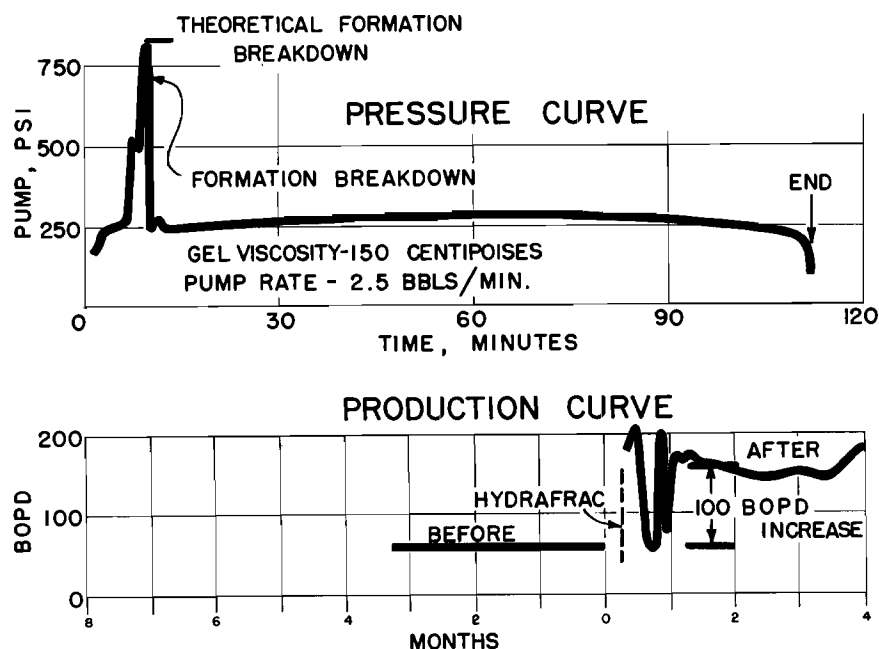


FIG. 4 — PRESSURE AND PRODUCTION CURVES FOR WELL BB, FRANNIE FIELD, WYO.

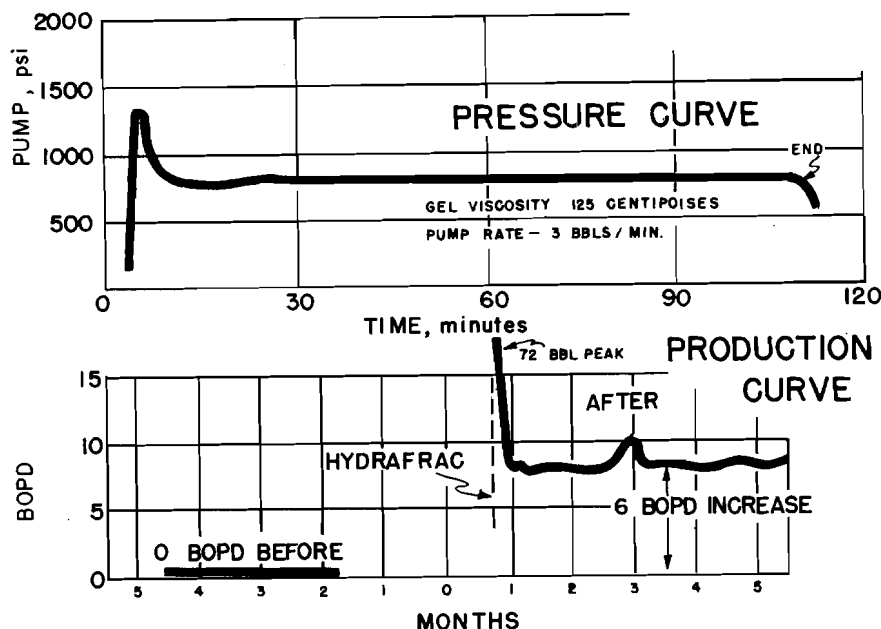


FIG. 5 — PRESSURE AND PRODUCTION CURVES FOR WELL FA, EAST SASAKWA FIELD, OKLA.

pressure curve taken during the Hydrafrac job showing the formation breakdown.

The effect on the permeability of selectively fracturing the producing formation of Well EF, Rangely Field, Colorado, is shown in Figure 8 by a comparison of permeability profiles run before and after the Hydrafrac operation. The location of each Hydrafrac job is shown between the two permeability profiles. An effort was made to have the same injection pressure for both permeability profile tests, but pump capacity prevented obtaining as high an injection pressure after Hydrafrac as was obtained before. Some of the permeable zones indicated on the "Before Hydrafrac Permeability Profile" are not evident on the "After Hydrafrac Permeability Profile" due to the lower injection pressure. However, the increase in the permeability of those sections treated as the result of hydraulically fracturing the formation is clearly evident in this figure.

Figure 9 shows the production after Hydrafrac for these five oil wells successfully treated by this process. It will be noted in all instances that a sustained increase in production was accomplished by Hydrafrac.

Well Showing No Sustained Increase in Production

No increase in production was obtained in 12 of the 23 wells treated in the preliminary experimental program. Considering the many variables involved, and the imperfections of present special packers, the proportion of failures at this stage of development is

not discouraging. Both theory and field experience show that it is necessary to obtain a definite formation breakdown in order for the process to function satisfactorily. Figure 10 shows the pressure curve and the production curve of Well EC, Rangely Field, Colorado, in which the formation did not breakdown and, as expected, no increase in production was obtained.

A comparison of Well EF and Well EC in the Rangely, Colorado Field illustrates the need for the proper isolation of the desired zones to be treated. It was possible on Well EF with suitable formation packers to confine the Hydrafrac fluids to the desired zones thus fracturing the pay formation in the most prolific sections. However, on

Well EC where the Hydrafrac operations were attempted without the benefit of packers, the hydraulic fracturing fluid was dispersed over the entire area of the open hole with a resulting failure to increase well production.

Production data on the 23 wells treated by Hydrafrac are shown in Table 3. It may be noted that the productivity of three of the wells treated in the Rangely Field seem to have been slightly decreased by the Hydrafrac treatment. This decrease in well production after treatment is believed to be a result of either well workovers before treatment, or normal production decline during the well testing period. For example, the pay zone in Well EA was charged with crude oil before Hydrafrac treatment during a cleanout of the hole while using crude oil as a drilling fluid, and sufficient time was not allowed for the well production to level off before the well test taken before Hydrafrac treatment. The decrease in production of Well ED after treatment represents the normal production decline for this well. Part of the production decrease of Well EC may be attributed to normal production decline; however, trouble occurred which it is believed accounted for most of this decrease.

Predictability of Results

If the engineering factors surrounding a proposed Hydrafrac job are known, experience has shown that correct prediction of success or failure of the job is usually possible. A careful review of the jobs done to date leads to the conclusion that, even with due regard to the fact that "hindsight is clearer than

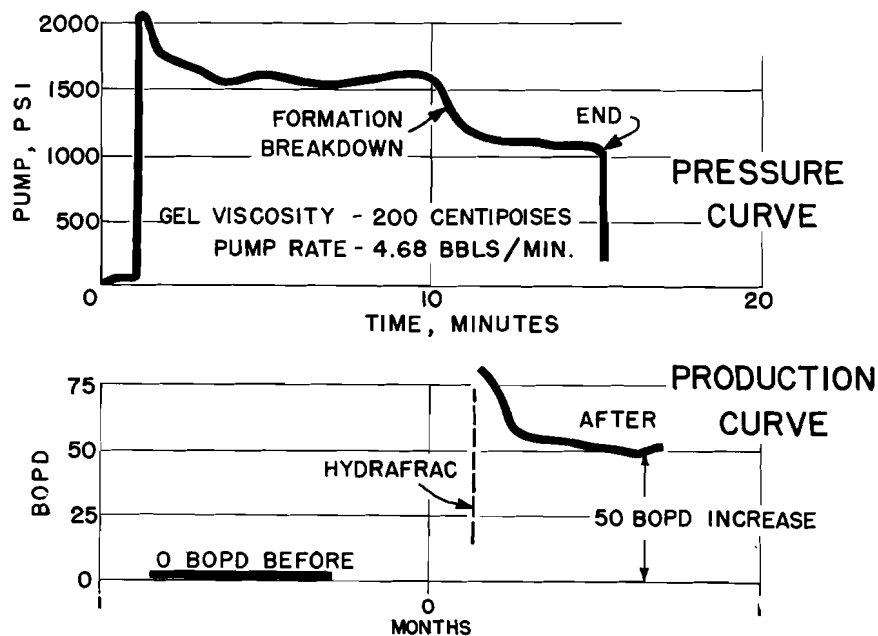


FIG. 6 — PRESSURE AND PRODUCTION CURVES FOR WELL GA, EAST TEXAS FIELD

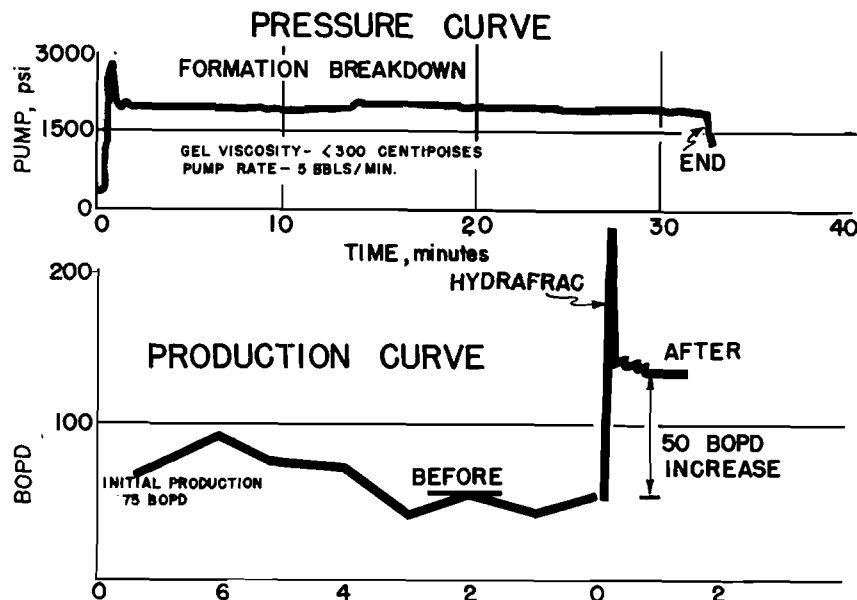


FIG. 7 — PRESSURE AND PRODUCTION CURVES FOR WELL EF, RANGELY FIELD, COLO

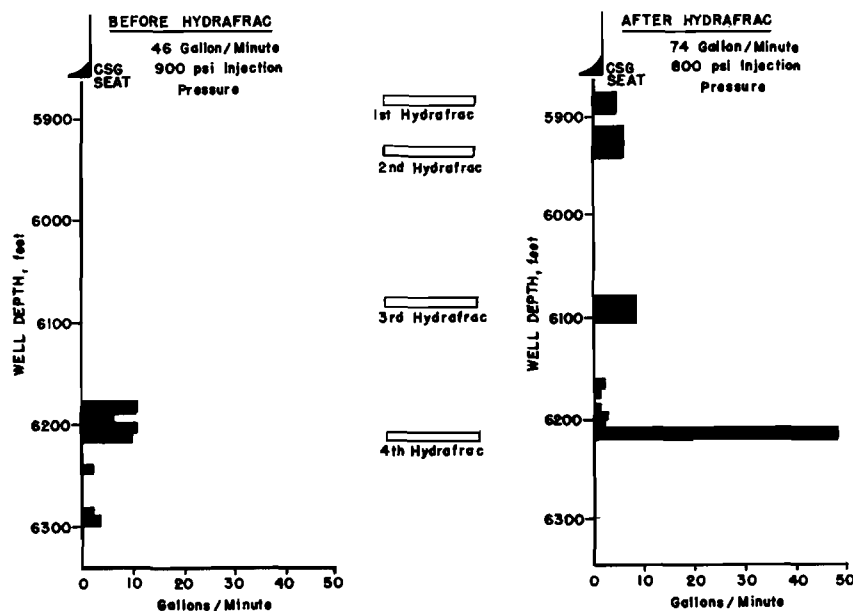


FIG. 8 — PERMEABILITY PROFILES INDICATING RESULTS OF HYDRAFRAC TREATMENT, WELL EF, RANGELY FIELD, COLO.

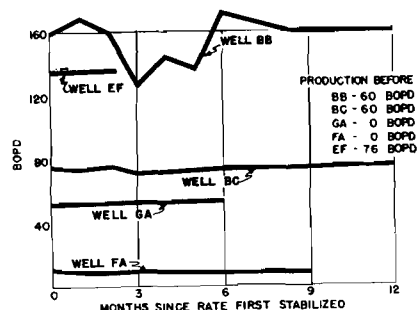


FIG. 9 — PRODUCTION AFTER SUCCESSFUL HYDRAFRAC TREATMENT.

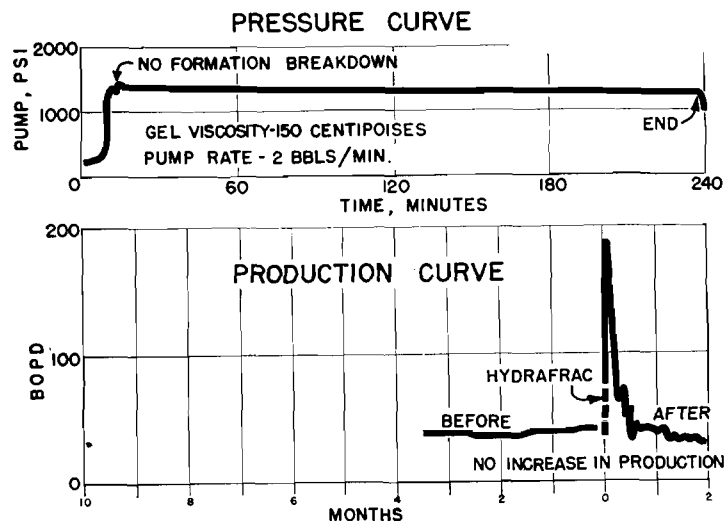


FIG. 10 — PRESSURE AND PRODUCTION CURVES, WELL EC, RANGELY FIELD, COLO.

foresight," it would have been possible to predict correctly at least 75% of the failures, and 95% of the successes, had all of the present field experience been available before each of the jobs done. As a matter of fact, many of the failures were predicted as such, and the jobs purposely done in the face of unfavorable well conditions in order to obtain research data. Incidentally, one of the treatments done under such circumstances (Well FA) was successful in spite of predicted failure.

Cost

When put into routine commercial use, the cost should be not much more than the cost of an acid job of corresponding gallonage. Where crude oil from the lease can be used as the base fluid in the Hydrafrac process, it is quite probable that the cost will be less than that for acidizing.

It is significant that the value of the additional oil and gas produced to date through the benefits of this process has already exceeded the combined cost of research, development, and all field tests.

ACKNOWLEDGMENTS

Acknowledgment is due Messrs. R. F. Farris, C. R. Fast, G. C. Howard, J. A. Stinson and other members of the staff of the Stanolind Oil and Gas Company's Research and Producing Departments for their part in the development of this process. Appreciation is expressed to the Management of Stanolind Oil and Gas Company for permission to publish this paper.

REFERENCES

1. Yuster, S. T., and Calhoun, J. C., Jr.: Pressure Parting of Formations in Water Flood Operations. *The Oil Weekly* (March 12 and March 19, 1945).

DISCUSSION

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By Wm. D. Owsley, Technical Adviser, Halliburton Oil Well Cementing Co., Duncan, Okla.:

I wish to highly commend Mr. Clark and his associates for this important contribution to oil production. Even at this early date in the development of this process, it is apparent that Hydrafrac can be of great value to oil producers, especially in view of the present high price of crude oil, attended by scarcity of casing and heavy increases in drilling costs. In spite of this statement, this process should not be regarded as a cure-all for any and every well.

Considerable thought has been given to the hazards attendant to the use of the Hydrafrac process. These hazards to personnel and equipment must be recognized; however, they can be minimized by simple and easily applied safety precautions. The mixing equipment can easily be arranged to prevent splash over. Precautions must be taken against leakage on all lines during the course of the job. It is suggested that this process be performed during daylight hours to reduce hazards attendant to accumulation of vapors during the night. Diesel engine powered pumping equipment offers an advantage over gasoline engine equipment in the elimination of possible fire hazards. Precautions can be taken in piping away exhaust stack gases and cooling of manifolding to prevent possible explosion.

The pumping of crude oil, diesel fuel, or gasoline, under high pressures is not considered dangerous, provided leakage in the system is prevented. There will be no occurrence of diesel effect to give explosion within the pumps or pipes unless large volumes of air be trapped within the system. Even then an intimate mixture of the vapors with air and a rapid increase in pressure to produce heat would be necessary in order to produce an explosion.

The problem of packers for segregation of short sections of open hole does offer several difficulties, and it appears that a packer design different than anything now known to be in existence is necessary. It is assumed that Hydrafrac can be applied to wells which have been gun perforated for production, in which case, the packer problem is much less difficult, since packers are already in existence which will adequately

handle this condition.

There has been some thought given to difficulty with reciprocating pumps in the handling of a sand-laden fluid of the nature described. Experience in the past in handling sand of large granular size through reciprocating pumps has not been good; however, it appears that the use of thickened oil phase agents eliminates this problem.

In the use of this process, it is recommended that surface piping and manifolding to the well head be kept as simple and direct as is practical to offset line losses during rapid pumping. This will greatly assist in obtaining high injection rates into the well itself without excessive pump pressure.

While this paper presents Hydrafrac in its application to wells which have been partially depleted, it would appear that in many cases of new wells initial potential might be considerably improved by application of this process. It is believed that with proper study of all data on any well which is being considered for the use of this process, its correct application should result in a high percentage of success.

☆

By Paul E. Fitzgerald, Dowell Incorporated, Tulsa, Okla.:

Mr. Clark has presented a paper on a subject which has been discussed by petroleum engineers for years. Most engineers realize that pressure parting or formation lifting probably plays an important part in many wells where fluids are injected for various reasons. The author has furnished some valuable quantitative data bearing on this interesting phenomenon.

The pressure parting phenomenon has long been recognized in well acidizing operations. In numerous cases where the formation permeability is quite low it has been observed that the initial acidizing pressure will exceed the pressure required to lift the overburden. At pressures below this critical value the formation will take substantially no fluid but when a pressure sufficiently high to part the formation has been reached it will take fluid and the rate of fluid injection can be raised with little or no increase in the injection pressure.

After the acid enters the formation a chemical reaction takes place in which a portion of the formation is actually dissolved away thus further enlarging the previously established

fracture. As the characteristics of the rock are not uniform, more rock will be dissolved by the acid in some places than in others so when the treatment is concluded the pressure parted fractures will not close but will still be open and will serve as flow channels to the well.

Mr. Clark has extended the application of the pressure parting idea by using fluids of increased viscosity and inert solid particles. These materials make the process applicable to wells having high permeability and to wells in which the producing section is not acid soluble.

☆

By C. P. Parsons, Houston, Texas:

There is considerable need for such a process.

Step 1 in the process calls for "injecting a viscous liquid, containing a propping agent, under high pressure to fracture the formation". This step is amply supported by the established practice of fracturing formations and squeezing cement and other fluids into oil sands.

Step 2 calls for "causing the viscous liquid to change from a high to a low viscosity so that it may be readily displaced from the formation". For this step there is no precedent in oil well cementing, primarily because the fluids used are viscous because of suspended solids; also because the fluids are intended to remain in the formation. Cement slurry, for instance, after injection into the fracture under high pressure increases in viscosity and changes into a plastic and finally a solid.

The second step presents the main problem in the process. The paper indicates two ways to overcome it. One way is by the use of an oil base liquid that temporarily has been made highly viscous but which will automatically revert to low viscosity after it is in place in the formation. That, of course, is the ideal answer to the problem. The other way is to follow the injection of the viscous gel with an injection of a gel-breaker. The paper does not make it clear which of the two alternatives were used in the actual field tests.

With regard to the following up with a gel-breaker, it is difficult to understand how the breaker could effectively reach out through the tightly confined thin layer of viscous gel to cause the change from high to low viscosity. It is conceivable, however, that the gel-

breaker could physically push the viscous gel ahead of it, causing the gel to spread out to a distance where the gel can no longer hold itself into a continuous ring and must disperse further in streaks, leaving openings for the gel-breaker to physically break through. The low viscosity of the breaker would permit it to come back out of the channels followed by newly released oil out of the formation. In addition, the gel-breaker, by having increased contact with the gel, would cause some of the gel to become less viscous. This would allow some of the gel to come out of the formation and thereby assist in the return of the breaker and release of oil. As to the propping agent, due to drag, it might not completely follow the viscous gel through the fracture. This could be an advantage when the gel breaker and released oil come out of the formation.

The process is a distinct contribution to the industry's important aim of increasing the productivity of oil. It is

along sound, practical lines and should be encouraged and followed up with many more field tests.

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Author's reply to Mr. C. P. Parsons:

Mr. Parsons in his comments discussed the breaking of the fracturing fluid viscosity. He mentioned two of the methods used and asks which of these methods were used in the field experimental work.

Three methods are currently available for breaking the viscosity of the Napalm gel, any one of which we believe will do the job. These methods are:

- (1) The unstable nature of the Napalm gel at bottom hole temperatures and pressures, in the presence of crude oil, will cause this gel to revert to sol in 8 to 24 hours.
- (2) The addition of a small amount, $\frac{1}{2}\%$ to 1% , water to the Napalm gel, plus the quiescent con-

tact of this gel with salt water, will cause it to revert to sol within an hour or two.

- (3) Napalm gels, when in quiescent contact with gel breakers such as petroleum sulphonates, will revert to sol in a few minutes.

Actually in field practices all three of these methods have been used to insure complete reversion to sol of all the Napalm gel in the well, and thus to avoid the danger of plugging of the formation with the viscous oily medium.

The action of the gel breaker in the fracture filled with a viscous gel solution may be very much as Mr. Parsons describes. It is believed, however, that the quality of the Napalm gel that causes it to revert to sol on quiescent contact with petroleum sulphonates, salt water, and some type of crude oil, is the primary reason why these gels do not plug the formation.